COMPTON
PETROLEUM CORPORATION

1998

ANNUAL REPORT

Corporate Profile

Compton Petroleum Corporation is a Calgary based company actively engaged in the exploration, development and production of natural gas, natural gas liquids and crude oil in Western Canada. The Company's capital stock is listed and trades on The Toronto Stock Exchange under the trading symbol CMT.

Compton began operations in 1993 with $1 million of share capital, a small dedicated technical team and a large seismic data base. The objective was to build a company from the ground up through internal full cycle exploration complemented by strategic acquisitions. Our goal was the creation of a company capable of long-term sustained growth.

Compton's focus and strategy has remained unchanged from the beginning. Five years later, the Company exited 1998 with production of 10,012 boe/d, reserves of 34 million boe, control of over 1,000 sections of undeveloped land and assets with a value in excess of $300 million.

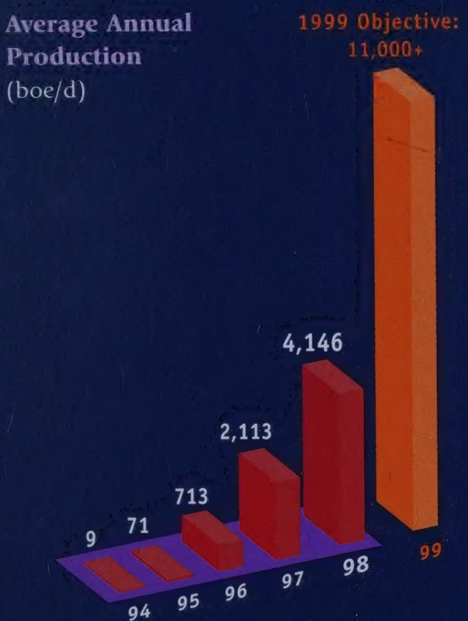
We are proud of our past achievements; 1998 was a banner year and we look forward to 1999. This annual report presents the results of our 1998 activities, our goals for 1999 and the resources available to Compton to achieve these goals.

Net Asset Value
($/share, 15% DCF)

Annual Meeting

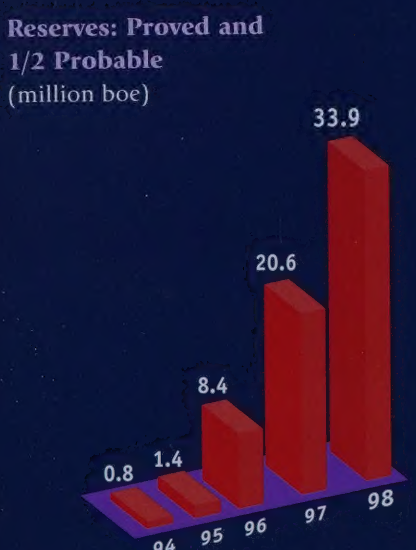
The Annual General Meeting of Shareholders will be held on Tuesday, June 22, 1999 at 4:00 p.m. at the Bow Valley Conference Centre, 3rd Floor, Bow Valley Square II, 205 – 5th Avenue S.W., Calgary, Alberta.

Highlights

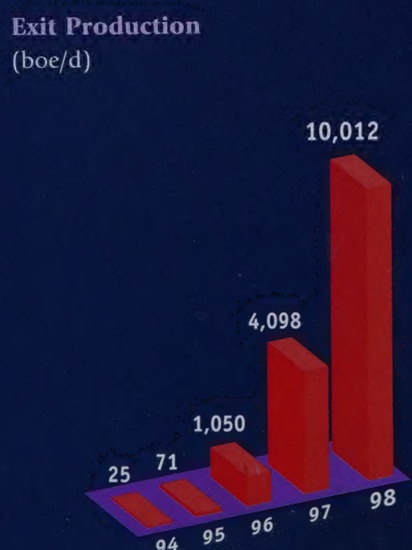


Average Annual Production
(boe/d)
1999 Objective:
11,000+
9
71
713
2,113
4,146
94
95
96
97
98
99

Average Cash Flow
($ millions)
1999 Objective:
44+
.1
.2
2
10
17.5
94
95
96
97
98
99



Reserves: Proved and
1/2 Probable
(million boe)
0.8
1.4
8.4
20.6
33.9
94
95
96
97
98



Exit Production
(boe/d)
25
71
1,050
4,098
10,012
94
95
96
97
98

Foundation for

Long term sustainable growth results from exploration, development and exploitation. Successful companies understand and possess the key fundamentals for growth.

Seismic & Technology

- Large seismic data base
- More than 40,000 kilometres
- Includes both 2D and 3D seismic
- Four geophysicists
- Eight geologists
- Six engineers

Undeveloped Land

- Five core areas
- Control of over 1,000 sections of undeveloped gas prone lands
- High working interest and operatorship

Infrastructure, Processing and Operations

- Control and/or ownership of processing and infrastructure
- Guaranteed access
- Control of operating costs

Sustained Growth

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Experienced Management Team

- Management and directors with large share ownership, share the risks with shareholders
- Established track record – Company has been built from grassroots
- Understanding of the business
  - focused strategy
  - exploration is key to long term growth
  - fundamentals must be in place
  - industry cycles create low cost opportunities
  - act confidently and decisively on opportunities
- Cohesive teamwork
- Established a strong financial position

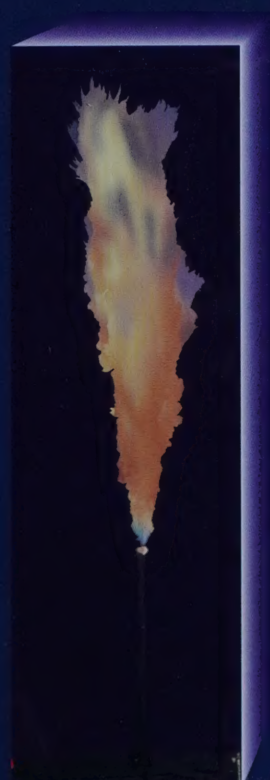
Exploration and Exploitation

- Internally generated prospects
- Low historical finding and development costs
- Reinvestment ratio >2:1
- 1999 aggressive drilling program
  - 65 wells (55 net)
  - 50% exploratory/50% development
- Continued focus on long-term deep gas

Production and Reserves

Quality long term multi-zone reserves and production that can promote and support growth for years to come

- 70% gas
- 34,000 mboe
- Low decline rates
- High netbacks
- 1998 exit rate: 10,012 boe/d



President's

1998 was an outstanding year for Compton Petroleum Corporation, full of activity and positive results.

Our strategy for growth and value creation has remained focused and essentially unchanged from our beginnings in 1993. Compton's adherence to this strategy has resulted in a company with the following results:

- 10,000 boe/d of production
- Control of over 1,000 sections of undeveloped gas prone lands
- A large balanced inventory of exploration and exploitation prospects
- Reserves totaling 34 million boe, 70% natural gas
- Low historical finding costs - 4 year average of $5.14 per boe (1998 - $4.70)
- Access to required processing capacity
- A large 40,000 km seismic data base
- Experienced, competent and committed management and staff
- A strong balance sheet with debt of less than 2 times forward cash flow
- An internally funded 1999 capital expenditure program of $64 million
- A reinvestment ratio exceeding 2 to 1

Compton has assembled all the essential elements for sustained growth and value creation for our shareholders. The pieces of the puzzle are all in place and Compton's primary focus for 1999 will be, in a single word - drill.

E.G. Sapieha, CA
President and Chief Executive Officer

Drilling Profile

Compton retains high working interests in the majority of its properties. Historically, the Company has targeted deep (2,000 metres plus), liquids rich gas horizons with large, low decline rate reserves. These targets remain our primary focus; however, we are drilling in areas with multi-zone potential, including uphole, shallow gas reserves that, with strengthening gas prices, have become increasingly valuable. In 1999, Compton will also pursue its significant shallow gas potential together with light oil prospects acquired through the J.M. Huber Canada Limited. We understand the risks and have a highly qualified exploration team in place, with deep drilling experience, to pursue an aggressive and balanced drilling program.

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Understanding the Business

Within the oil and gas industry, and particularly among junior exploration and production companies, value is created and sustained growth is achieved through a successful exploration and development program. You must be able to find hydrocarbons with low finding and development costs and build from there. However, for a corporation to implement a successful long-term drilling program, a number of fundamental elements must be in place. Over the last few years, culminating in 1998, Compton has assembled:

- A large and geographically focused prospective land position with an extensive inventory of prospects
- A technical team with expertise and experience in all areas of operations
- The necessary financial resources to fund its activities
- Processing capacity with reasonable operating costs
- A cohesive management team with the vision, ability and commitment necessary to bring it all together

The management team and Board of Directors have understood the basics from the beginning. Additionally, we recognize the cyclical nature of the industry and opportunities provided by the downturns. In building Compton from the grassroots, we have identified and capitalized on these opportunities. Our timing has been excellent.

We started in Southern Alberta when gas was at the bottom of the cycle. We acquired an under utilized world class gas plant when prices were low and then levered control of the infrastructure into a dominant land position in over 700 sections of gas prone lands. When gas prices recovered, we monetized the plant to become debt free. This allowed us to commence an aggressive drilling program for gas and to acquire J.M. Huber Canada Limited for $100,000,000 cash. The Huber acquisition capitalized on low oil prices, weak equity markets and gave the advantage to Compton's cash offer. We have used the same rationale in the Rainbow area of Northern Alberta, acquiring undeveloped gas prone lands in 1996 where no pipelines existed. Nova has now built a pipeline through the middle of our lands and we have drilled two gas discoveries with a potential for 15 follow up locations to be drilled in the first quarter of 2000.

1998 Corporate Activities

We are very proud of the results of our efforts to date. At the beginning of 1998, we set out four goals, as noted below:

- Invest heavily in human resources to expand our technical and professional team
- Establish and maintain a strong financial position
- Pursue strategic acquisitions consistent with our overall objective of value creation and sustained growth
- Commence an aggressive drilling program

We achieved those goals.

President's

I.J. Koop, P.Eng
Director

January to September 1998

Extremely hard work, long hours, and significant accomplishments characterized the first eight months of 1998. Compton shot a large 100 square mile 3D seismic survey in Southern Alberta, reviewed numerous acreage postings, acquired land at Crown sales, built 30 kilometres of pipelines, expanded and operated a major sour gas plant, competed for rigs, and drilled in Rainbow and Southern Alberta. We were also in extended negotiations with Mobil, PanCanadian and four major midstream companies. We successfully closed major land agreements with Mobil and PanCanadian and, in August, concluded the unique sale of our Mazeppa Plant to Dynegy for $62,000,000 cash plus a minimum of $12,500,000 of drilling incentives.

Compton made the conscious decision during the first half of the year, when funds were limited, to focus our resources on seismic, land and the expansion of tangible facilities, all with a view to the future. Finally, with the monetization of our processing facilities, we had the funds necessary to commence an aggressive drilling program. We had disappointments – things took longer than we expected. As a result, we did not have the funds to staff up or pursue the planned drilling program on our lands.

Looking back on those first eight months of 1998, Compton's effort was outstanding. Everyone from our Directors to our field staff went the extra mile. I remember walking back to our office with our Management Team on August 21st at 2:00 a.m. in the morning with a cheque for $62,000,000 in hand. We had closed the sale of our facilities and were debt free.

September to December 1998

We started September debt free, with limited staff, big aspirations and expectations. We quickly concentrated on adding professional staff, continued evaluating our seismic data and prospects, turned over the gas plant operations at Mazeppa and reviewed potential acquisitions. In December, we acquired J.M. Huber Canada Limited for $100,000,000 and accelerated our drilling program in Southern Alberta. In concluding 1998, we surpassed our objectives in a big way.

Outlook for 1999

1999's emphasis will be on drilling a significant number of high working interest deep natural gas prospects with multi-zone potential and exploiting and building upon our core areas. We will combine large exploratory targets with a balanced portfolio of shallow gas and a few light oil opportunities. 65 wells are planned for 1999. As I write my report, we have drilled 18 wells in the first quarter of 1999, experiencing very good results.

J. Preston
Director

Message

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Objectives for 1999

- Average annual production exceeding 11,000 boe/day
- Completion of our 65 well drilling program
- A recycle ratio of at least 2 to 1
- Finding and development costs of approximately $5.25 per boe
- Building upon our core areas
- A debt to cash flow of 2 to 1 or less

While our objectives for 1999 are simply stated, the proper execution and implementation are critical. We recognize our people are our most valuable asset. The Company's successes have been achieved by outstanding, qualified individuals acting as a team. Our personnel, at all levels, are experienced and enthusiastic. They have the skills, understand the risks and, most importantly, they have the motivation necessary to move Compton to the next level.

I would like to thank all of Compton's staff and Directors for their outstanding efforts and tremendous contributions in 1998. Of special note, we at Compton would like to say thank you to Norm Lamarche upon his retirement from Compton's Board of Directors. His contributions and enthusiasm were so welcome and valuable at Compton.

Additionally, a warm welcome to all the new employees who have joined Compton's team and have added to the vibrancy and excitement at Compton.

We have set very ambitious targets for 1999. Visit our offices and you will see and feel the exuberance, commitment and confidence of Compton. Combine this with our outstanding assets, fundamentals and strategy, and there is every reason to believe Compton will achieve its 1999 objectives.

Compton is an exciting company with great potential. We will execute and drill. We are just beginning.

M.F. Belich, Q.C.
Director

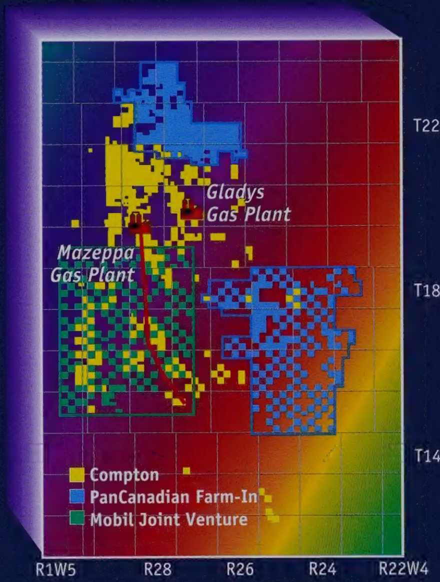
E. G. Sapieha
President and Chief Executive Officer

May 20, 1999

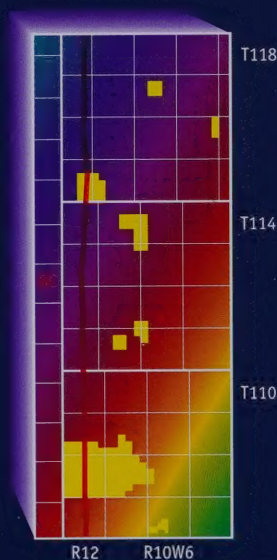
Core

Southern Alberta

- Acquired empty Gladys gas plant, 1994
- Expanded land base
- Production onstream
- $50 million CanOxy acquisition of reserves and plant at Mazeppa in 1997
- Built pipelines
- Control of infrastructure
- Acquired additional lands
- Monetized infrastructure in 1998
- Multi-zone deep gas
- Dominant land position



'93 - '98



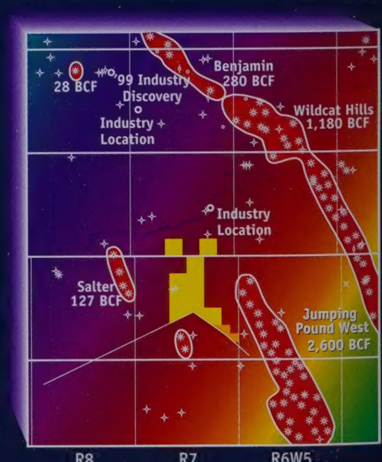
'96- '98

Rainbow

- Bought lands in 1996
- Multi-zone gas
- NOVA pipeline completed, 1998
- Two gas discoveries
- Evaluation by Year 2000

Foothills

- Acquired lands in 1998
- Multi-zone deep gas
- Evaluate with seismic in 1999



Areas

98

1999 Drill Plans

'99

Going Forward

- $64 million capital budget
- Aggressive drilling program
  65 wells (net 55)
  - 50% exploratory
  - 50% development
- > 1,000 sections of undeveloped land

'98

Huber Acquisition

- $100 million acquisition December 1998
  - $11 million working capital
  - $5 million undeveloped land
  - $2 million seismic
  - $82 million reserves
- 5,500 boe/d production
- 12 million boe proved reserves
- 13 million boe proved plus $^{1}/_{2}$ probable
- Two new core areas
  - Bigoray
  - Peace River Arch

Exploration

Building upon the successes of 1998, Compton will establish 1999 as the year of the drill bit.

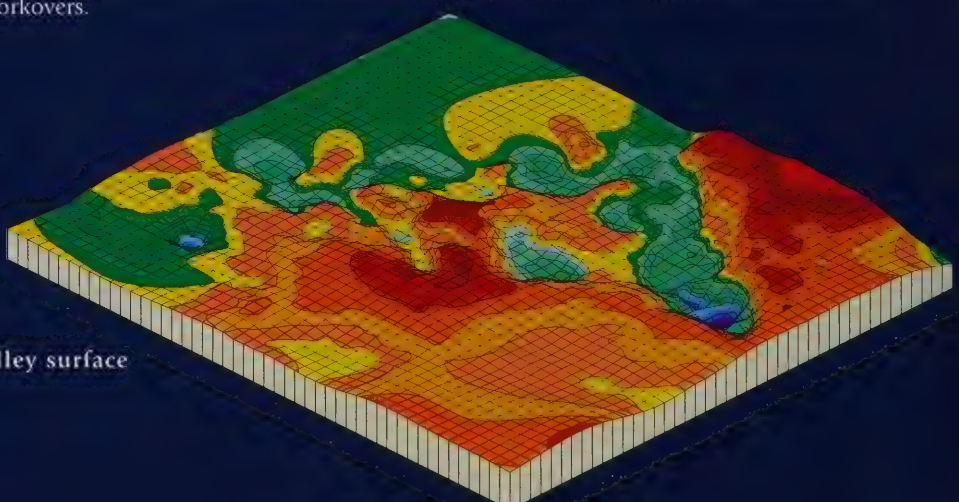
Compton's exploration growth strategy since inception has been to establish dominance in focused core areas. This is accomplished through combining large deep gas potential land bases and technical creativity. This strategy enhances the Company's ability to gain superior geographic expertise to develop successful multi-year drilling programs and to operate efficiently in medium to high-risk high impact areas. Exploration opportunities are complemented with acquisitions to balance risk and to increase Compton's presence in core areas.

By the spring of 1998, Compton had gained control of over 700 sections of natural gas potential lands in the Company's first core area in southern Alberta. A year of land acquisition efforts followed by detailed technical work has led to a 105 multi-zone prospect inventory, concentrated on deep, long life, gas bearing carbonates. This highly prospective region will dominate Compton's 1999 drilling program. Through the year, Compton increased its land base to 160 sections of lands in the developing second core area of gas prone West Rainbow. Compton is working towards establishing gas production from this pure exploration area in the first quarter of 2000. Compton concluded 1998 with the acquisition of J.M. Huber Canada Limited, which established two new core areas for future growth at Bigoray and the Peace River Arch.

An experienced motivated exploration team has been formed, consisting of eight geologists and four geophysicists. Compton employs the necessary technology and resources to assure the optimal development of the Company's opportunities. Seismic is a valuable tool for exploration and development activities and Compton has access to approximately 40,000 km of 2D data and over 500 square km of modern 3D data.

All the components are in place and Compton is pursuing an aggressive drill program into 1999 that will set the stage for continued growth through the drill bit into the 21st century.

The planned 1999 capital expenditure budget is $64 million. Drilling and completions are budgeted for the majority of these funds, with $41 million allocated towards 65 high working interest wells plus re-completions and workovers.



Turner Valley surface in time

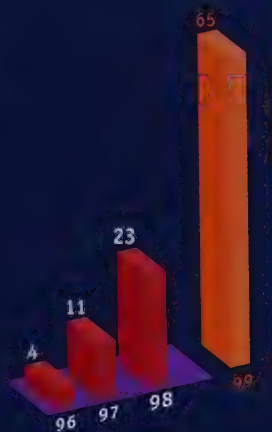
Development

1998 Wells Drilled

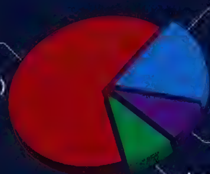
	Gross	Net
Natural Gas	11	8.75
Oil	3	2.50
Dry and Abandoned	9	7.00
Total	23	18.25
Success Rate		62%

Kim Davies, P.Geoph
V.P. Exploration

Gross Wells Drilled



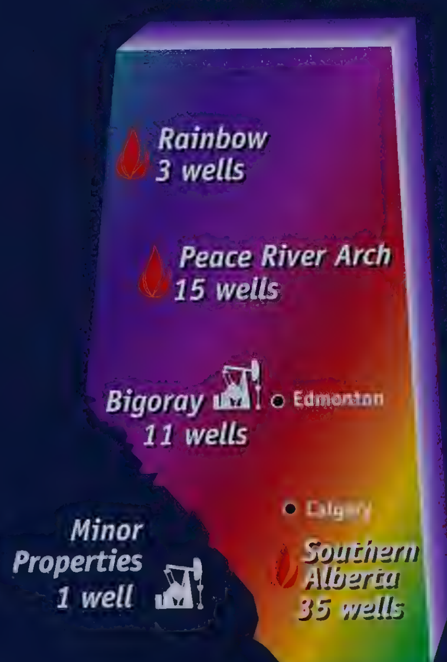
1999 Budgeted Capital Expenditures – $64 million
($ millions)



1999 Drilling Program

- *65 wells (55 net) drilling program*
- *50% exploratory*
- *50% development*
- *Multi-zone, deep gas*
- *Deep gas priority*

1999 Drill Plans

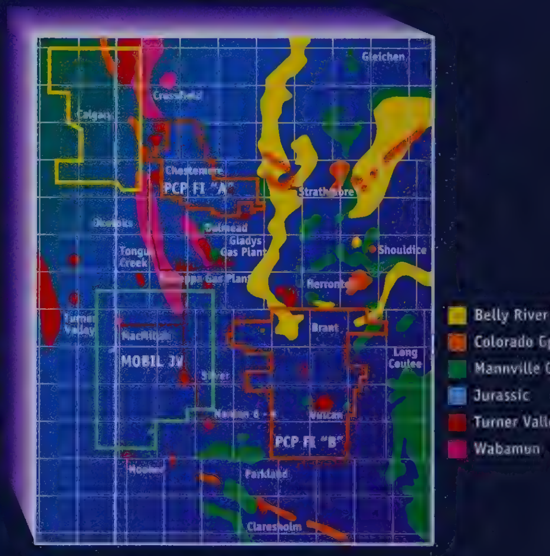


Exploration

Southern Alberta

Compton's southern Alberta properties stretch from Calgary to the Keho area, 75 miles to the south. The properties are made up of over 700 sections of land, comprised of over 300 sections of Compton land with an average working interest of 87%. Of the remaining land, 155 sections are accessed through a joint venture with Mobil and 250 sections of lands are accessed through a farm-in with PanCanadian.

A multitude of producing zones trend into these lightly explored lands. These areas are highly gas prone with multi-zone reservoirs. Compton's main targets lie in the deep liquid rich natural gas of the Turner Valley and Wabamun carbonates. Reserve sizes range from 3 to 40 bcf per well, with production capabilities of 2 to 10 mmcf/d per well, with associated liquids averaging 20 bbls/mmcf. Compton's understanding of these prospective zones and a number of others in the overlying Cretaceous section. Additional prospects have been defined in the Belly River, Bow Island, Ellerslie, Sunburst, Basal Quartz and Jurassic sands.



Calgary to Claresholm producing reservoirs

In 1998, 19 wells were drilled in this area, resulting in 9 gas discoveries, 2 oil wells and 8 dry holes.

At least 35 wells are planned on these lands in 1999, of which 10 were drilled in the first quarter, including approximately 22 Turner Valley or deeper wells. Compton currently has a 105 well prospect inventory.

Compton Corporate Lands – Gladys to Nanton

These areas mostly comprise Compton's original lands, acquired through acquisitions and land sales from 1994 to 1997. Activities in 1998 were mainly developmental in nature.

Five wells were drilled at Gladys, which lies 50 km south of Calgary. Three targeted the Crossfield member of the Wabamun Formation. Of the two wells looking to extend the north end of the pool, one was successful and one was tight in the Crossfield but found gas in the Belly River. A third well near the main production was unexpectedly tight, but is slated for a horizontal re-entry in 1999 to access better reservoir. These wells typically define 4 bcf/well.

Two additional wells drilled at Gladys included an Ellerslie gas well and a mechanically unsuccessful horizontal in the Turner Valley oil pool. Two Turner Valley gas wells were drilled at Tongue Creek and Shepard. A final well encountered Bow Island oil.

Compton's 1999 plans continue to be mainly developmental, with the Crossfield being of major interest. The Crossfield at Gladys is a low permeability, low porosity reservoir with significant reserves over a large area. Compton is investigating ways to optimize the value of this asset and to increase production from this

field. Down spacing, through new drilling and deepening of some existing well bores, appears to be the most likely method of achieving these aims and Compton has initiated this process. More significant gains are anticipated to come from development activities in the Okotoks/Mazeppa Crossfield pools that Compton acquired from Canadian Occidental in 1997. The Crossfield reservoir quality in these areas is superior to that at Gladys with some wells having produced 10 to 50 bcf. The exploitation of this quality reservoir will begin in the second half of 1999. Compton has identified four undrilled spacing units in the field and several re-entry candidates. These are excellent opportunities; however, they are sour gas with 33% sulphur. Compton will be proceeding expeditiously, employing its extensive sour gas drilling and handling experience with community consultations.

Up to six Turner Valley and Basal Quartz wells are planned in 1999 from south of Calgary to Nanton. The Belly River at Gladys and its environs will also garner attention in 1999. Belly River gas potential was identified up-hole in several well bores targeting deeper zones and mapping has indicated a significant trend on Compton lands. Initial results from the first two wells drilled for this zone early in 1999 are very encouraging.

Mobil Joint Venture

In 1998, Compton and Mobil formed an 11 Township Joint Venture where Mobil contributed 155 sections of land to be earned by drilling. An extensive seismic grid exists through combining the two companies' data bases. This area stretches from High River to Nanton and encompasses some of the most lightly explored lands in Western Canada. At that time, the only production from this area was from Compton's Turner Valley Silver Pool. In the fall of 1998, Compton had a new discovery at High River 15-18-18-29W4 (MacMillan), which came on production in late February 1999. The MacMillan Pool is currently producing about 5 mmcf/d of gas and 150 bbls/d of condensate net to Compton from two wells.

Technical complexities contributed to several unsuccessful Turner Valley wells around Silver, particularly in the first half of 1998. The knowledge gained on these dry holes was invaluable for re-defining the geological models in this highly prospective exploratory area. The MacMillan discovery was followed up early in 1999 with a new pool discovery approximately 10 miles to the south at 10-33-16-29W4, which tested at a restricted rate of 3.5 mmcf/d with 165 bbls/d of condensate. The Bow Island also appears prospective in this well. Two further wells were drilled in the Mobil block, an unsuccessful Bow Island Wildcat and a deep Crossfield well that was cased and is confidential.

Nine wells are planned for 1999, all targeting Basal Quartz, Turner Valley or deeper. Four additional locations have been identified to date along trend with the "MacMillan" structure. Other prospects have been seismically identified to the east and west, including a large Turner Valley feature at 3,700 metres.

PanCanadian Farm-In

Compton farmed-in to two large blocks of land totaling 250 sections in April of 1998. The Chestermere block is just east of Calgary and the Vulcan block stretches from Herronton to south of Vulcan. Compton also gained access to significant additional amounts of PanCanadian seismic as part of the deal. These lands are prospective for multi-zones, particularly the Turner Valley. Belly River, Ellerslie, Glauconite and Basal Quartz are also being pursued. While the lands have seen significantly more drilling activity then

the Mobil block, the area is still very exploratory with significant room for discoveries. Three wells were drilled on these lands in 1998, resulting in one oil well and two dry holes.

Further seismic has been shot, including a first quarter 1999 3D program on trend with a 4 mmcf/d Turner Valley well. The 3D seismic will greatly enhance the interpretation of the structural and erosional complexity of the Turner Valley. At least seven Turner Valley tests are planned in 1999. A significant shallow gas trend has been mapped and successful drilling commenced on this in early 1999. A new multi-section Basal Quartz prospect, containing an abandoned well that tested over 3 mmcf/d, has also been identified.

Rainbow

The extreme northwestern portion of Alberta was a major oil domain where gas was an unwanted by-product of drilling for deeper targets. Significant gas discoveries and shows were frequently encountered, however, transportation options were limited or non-existent until quite recently. Compton realized the large undeveloped gas potential of this region and began acquiring land in 1996 for future development. Compton now has a working interest in 160 sections of undeveloped land. Targets include shallow Bluesky and Mississippian zones as well as deeper Devonian carbonate reservoirs.

In the first quarter of 1998, Compton made a shallow Bluesky discovery. The deeper Slave Point at this location, offsetting a suspended well that tested 4 mmcf/d, encountered significant porosity but was wet. Late in 1998, Compton initiated a 3D program around the discovery, primarily to delineate deeper prospects. Three wells were drilled, resulting in a new pool discovery that is currently confidential. A Bluesky development well was wet but has established the gas/water contact on the pool. An exploratory Elkton subcrop well found reservoir quality rock but was also wet. Future developments will concentrate on moving structurally up-dip from these locations.

The results of these wells and ongoing technical work has led to at least 20 follow-up and new prospect drilling locations. As anticipated in 1996, Nova Gas completed a pipeline through Compton lands in the spring of 1998. Compton is actively planning to have sweet gas on production in the first quarter of 2000. This will provide an operation base to allow continued exploration of the larger potential higher risk Devonian targets that will require sour gas processing facilities.

Foothills

Compton has acquired over nine sections of land in the Alberta Foothills at Stoney, and 22 sections on the military range of the T'suu Tina Reservation. These areas are on trend with prolific Turner Valley producers. Only one well has tested the Stoney land and the military lands have never been explored. Planning for seismic acquisition is currently underway for late in 1999.

Manitoba

Compton has acquired land over several prospects in oil prone Manitoba. This area was largely inactive in 1998 due to low oil prices but will be re-examined as economic conditions improve and stabilize. Two features have the potential for up to 2 million barrels of oil, a required threshold for Compton to justify continued efforts in this province rather than in gas prone areas. Compton had gained access to the Birdtail Sioux Reservation but has declined to continue activities after seismic data indicated the potential was limited.

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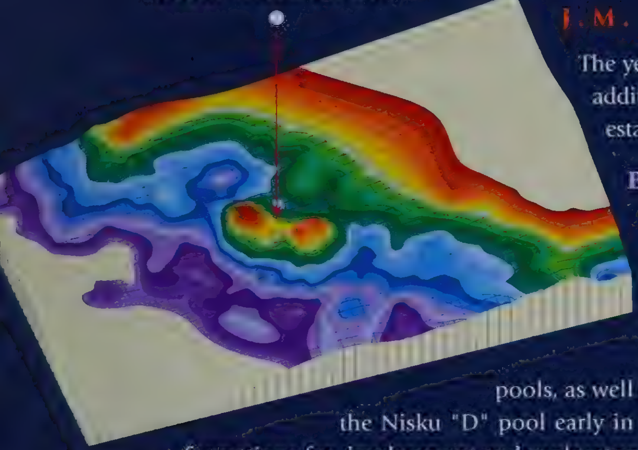
Development

Recent Nisku oil well



J.M. Huber Lands

The year end acquisition of Huber will provide Compton with additional exploration and exploitation opportunities with the establishment of two new core areas.

Bigoray

Compton now has access to 57 sections of land at an average working interest of 66% in a highly prospective area of west central Alberta. This region is Compton's only significant oil region. Substantial exploitation potential exists in three prolific Nisku oil pools, as well as in the Cardium. Compton drilled a 100% oil well in the Nisku "D" pool early in 1999 that tested at over 500 bopd. Other prospective formations for development and exploratory drilling include Mannville, Jurassic and Mississippian zones. Eleven wells are planned for this region in 1999.

Peace River Arch

Compton has 70 sections of land at an average working interest of 45% at Progress, Sexsmith/Saddle Hills and Howard. Compton now owns the largest interest in the Progress Halfway Pool with a 22% working interest. This highly competitive area has significant upside potential from numerous shallow and deep zones, particularly for gas. Fifteen wells are planned for the Arch in 1999.

Land

In 1998, Compton acquired 111,925 net acres of land at an average price of $68 per acre within its established core areas. An additional 63,890 net acres of undeveloped land were acquired through the Huber corporate acquisition. Compton has continued its land acquisition strategy by controlling prospective lands both within and on trend with its exploration efforts.

George Cracco
Land Manager

Undeveloped Land Summary

Year End 1998 (Acres)

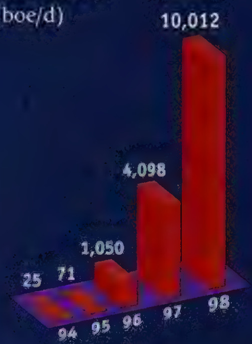
	Gross	Net
Compton	426,688	314,281
Mobil/PCP•	260,000	
Total	686,688	

•Farm-in lands

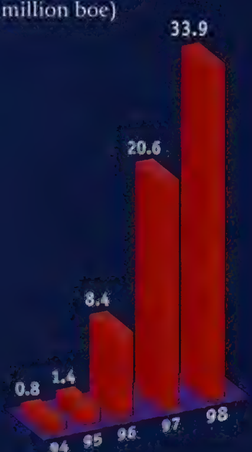
Compton has achieved an outstanding undeveloped land base growth of 124% consecutively over the last two years. As evaluated by Seaton Jordan, Compton's undeveloped land base at December 31, 1998 was valued at $28.7 million. Acreage value does not include the 405 sections of land Compton gained control of as a result of its major land deals with PanCanadian and Mobil in southern Alberta.

Operation

Exit Rates
(boe/d)



Reserves
Proved &
1/2 Probable
(million boe)



Production

The past year was highlighted by a 1998 exit rate of 10,012 boe/d. This is a 144% gain over the 4,098 boe/d in the previous year. The 1998 exit rate consisted of 61 mmcf/d of gas, 2,310 bbls/d of light oil and 1,600 bbls/d of natural gas liquids. The yearly average production effectively doubled to 4,146 from 2,113 boe/d.

Reserves

Compton's established reserves increased from 20.6 to 33.9 million boe in 1998. A 65% gain accomplished at $4.70/boe. Compton's proven reserves category represents 90.4% of the established reserves. Year-end reserves were comprised of 235.3 bcf of gas, 5.74 MMbbls of light oil and 4.65 million bbls of natural gas liquids. The reserves are long life, with an average corporate decline rate of 17% per year.

Operations and Facilities

In 1997, Compton purchased the Mazeppa sour gas processing plant, related pipelines, gas reserves and associated lands for $50 million. Our strategic plan was to purchase the gas reserves and to build a large gas prone land base in a depressed gas market and then separate the processing assets from the producing assets. A divestment of the tangible processing assets to a world class midstream company occurred in August 1998, when Compton sold the processing assets for $62 million to Dynegy Canada. With Dynegy funded drilling incentives, the $62 million offer increases to a minimum of $75 million and to a maximum of $87.5 million. The upgrade occurs through drilling incentive payments of $250,000 per dry hole and $500,000 per successful well for the next 50 wells drilled in the lands dedicated to the plant. The sale of the processing plant and pipelines placed Compton in a debt free position. Dynegy Canada has since proven to be an excellent partner in jointly developing deep sour gas reserves in lands just offsetting Calgary.

Prior to divesting the Mazeppa gas plant, Compton gained control of a significant Mobil and PanCanadian land base on offsetting lightly explored lands. The land deals gave Compton access to 700 sections of lands with liquids rich multi-zone gas potential. The plants and pipelines were sold with processing and plant expansion guarantees at fixed gas processing costs. The process fees are reasonable and only slightly increased the 1998 operating costs to $4.97/boe from the $4.94/boe 1997 cost. This midstream agreement was very unique and demonstrated both Compton's and Dynegy's creativity and commitment to the area.

COMPTON
PETROLEUM CORPORATION

Murray Stodalka, P.Eng.
V.P. Engineering & Operations

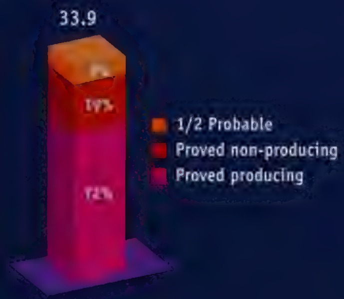
Compton continues to operate approximately 75% of its production including the Bigoray 9-8-51-9W5M battery and gas plant and the Gladys 6-15-20-27W4M gas plant and battery. All Compton operated sour gas wells Southern Alberta are SCADA controlled to ensure a safe and a highly efficient operation.

J.M. Huber Acquisition

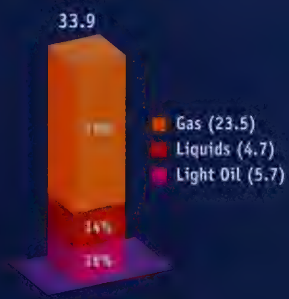
Compton took another bold step in December 1998. With the price of oil dipping to a 12 year low of US$10.62/bbl WTI, Compton announced the $100 million acquisition of J.M. Huber Canada Limited. The purchase included 5,500 boe/d, 13.4 million boe of reserves consisting of 50% gas and 50% oil and associated natural gas liquids, 100 sections of undeveloped lands and two new core areas: Bigoray and the Peace River Arch. These new core areas represented 71% of J.M. Huber's reserves and production. The purchase also offered Compton working interests in 13 separate gas processing facilities in areas that are generally tightly controlled. Having access to processing capacity is necessary to successfully expand in core areas such as Bigoray, the Peace River Arch and in the lands deemed as minor such Hotchkiss or Ghost Pine. With the recent return of more bullish oil prices, the purchase was timely. The minor properties purchased have proven to have considerable swap potential for consolidation in our core areas.

Finding & Development Costs
$/boe Proved + 1/2 Probable
(All-in costs)

1998 Reserves
Proved + 1/2 Probable
(million boe)



1998 Reserves
Proved + 1/2 Probable
(million boe)



Operation

Gladys and Okotoks Field Staff

Drilling, Completions and Operations

In 1998, Compton drilled a total of 23 wells (18 net) with an average well depth of 2,200 metres. This compares to 11 wells (10.5 net) in 1997. Compton has the experienced operations personnel who are drilling, completing and operating deep liquids rich sour gas wells in a safe and cost effective manner.

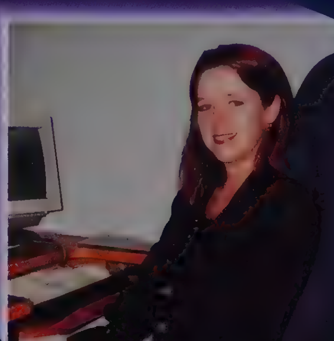
Marketing

Compton's average 1998 commodity prices in Cdn. funds were \$2.00/mcf, \$16.66/bbl of oil and \$17.34/bbl of natural gas liquids. This compares to the 1997 prices of \$2.04/mcf, \$25.89/bbl of oil and \$27.37/bbl of liquids. Aggregators market 70% of Compton's gas, while un-contracted gas indexed to AECO pricing represents 30%. Oil and natural gas condensates are indexed to the Edmonton par price. The oil is being sold to Dynegy. The natural gas liquids are being sold to Koch or to CXY Marketing. Neither oil nor natural gas liquid volumes are currently hedged.

Community Affairs, Environment and Safety

Compton is committed to conducting all operations, including drilling, completions and workovers, construction and daily operations in a safe manner to ensure that the safety and health of employees, contractors and community residents are protected. The Company is totally committed to operate in an environmentally safe manner. Compton complies with all current government and regulatory legislation and is staffed to manage continual regulation changes.

Compton and Dynegy have a joint emergency response plan for the Mazeppa and Gladys wells and facilities. The plan is approved by the AEUB and is the result of an extensive work effort by Compton and Dynegy personnel. Compton adheres to its Corporate Safety Manual and its Corporate Environmental Manual.

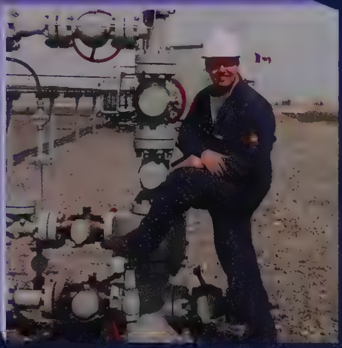


Allison Egeland,
Field Office Administrator

Gerald Dines,
Field Operator

Future Growth

Jim Ferguson,
Southern Alberta Foreman



Clark Williams,
Field Operator

The end result of Compton's aggressive corporate growth strategy is a company that is strategically positioned for continued growth in a 48-township block of Southern Alberta that stretches from Calgary to Nanton. A similar core area expansion plan is being creatively implemented by swapping non-core assets and selective acquisitions to grow the three new core areas. With drilling rig costs currently being 30% lower than 1998 pricing highs, Compton is positioned financially to grow by the drill bit.

As a result of the combined companies, Compton now has five core areas in which it plans to concentrate its efforts: Southern Alberta, Bigoray, Peace River Arch, West Rainbow and Foothills.

The production growth since the Company went public on the Toronto Stock Exchange in the fall of 1996 has shown a staggering gain from 300 to 10,000 boe/d (3,200% gain) in a period of two and one-quarter years. Compton has accomplished this using thorough strategic planning combined with teamwork and execution by dedicated personnel. Continued strong growth is our corporate focus.

Reserves Summary (Escalated dollar economics)

December 31, 1998

Reserve Category	Oil mbbls	Gas bcf	NGLs mbbls	MBOE 10 to 1	10% DCF $000s	15% DCF $000s
Proved						
Producing	4,563	167.0	3,024	24,286	$ 210,699	$ 173,103
Non-producing	3	31.4	493	3,637	21,446	16,218
Undeveloped	331	18.8	549	2,758	21,587	17,128
Total proved	**4,897**	**217.2**	**4,066**	**30,681**	**253,732**	**206,449**
Probable additional	**1,677**	**36.3**	**1,169**	**6,477**	**43,549**	**31,610**
Total before risk	6,574	253.5	5,235	37,158	297,281	238,059
Reduction due to risk	(838)	(18.2)	(584)	(3,237)	(21,774)	(15,795)
Total after risk	**5,736**	**235.3**	**4,651**	**33,921**	**$ 275,507**	**$ 222,264**

Reserves based upon independent reports prepared by McDaniel & Associates Consultants Ltd. and Outtrim Szabo Associates Ltd.

Management's D

Management's discussion and analysis of the Company's financial condition and results of operations is a review of 1998 activities and results as compared to the previous year. Comments relate to and should be read in conjunction with the consolidated financial statements presented elsewhere in this annual report. The discussion is intended to provide both an historical and prospective analysis of the Company's activities.

Financial Review and Analysis

Highlights

Operations

Year ended December 31	1998	1997	% change
Production			
Gas, mmcf/d	33.1	16.2	+104 %
NGL's, bbls/d	611.4	295.2	+107 %
Oil, bbls/d	222.9	195.5	+14 %
Boe/d	4,146	2,113	+96 %
Finding and Developments costs, per boe	$ 4.70	$ 7.06	-33.4 %
Reinvestment ratio	2.4 to 1	1.8 to 1	

Financial

Year ended December 31 ($000s except per share and boe amounts)	1998	per boe	1997	per boe
Revenue, net	$ 27,756	$ 18.34	$ 15,220	$ 19.73
Expenses				
Operating	7,477	$ 4.94	3,787	$ 4.91
General and administrative	1,517	$ 1.00	903	$ 1.17
Interest	1,023	$ 0.68	270	$ 0.35
Capital taxes	202	$ 0.13	224	$ 0.29
	10,219	$ 6.75	5,184	$ 6.72
Operating cash flow	$ 17,537	$ 11.59	$ 10,036	$ 13.01
Depletion, depreciation and amortization	6,671	$ 4.41	3,896	$ 5.05
Income taxes, deferred	4,262	$ 2.81	2,415	$ 3.13
Net earnings	$ 6,604	$ 4.37	$ 3,725	$ 4.83
Per share amounts				
Cash flow, basic	$ 0.20		$ 0.16	
Cash flow, fully diluted	$ 0.17		$ 0.14	
Earnings, basic	$ 0.07		$ 0.06	
Earnings, fully diluted	$ 0.06		$ 0.05	
Return on revenue	23.9%		24.4%	

Major Financial Transactions

Building on 1997 activities, Compton completed two major transactions in 1998, which had a significant effect the financial position of the Company.

- Compton was one of the first exploration and production companies to monetize its significant investment in midstream gas processing facilities. Effective July 1, 1998, Compton sold its interests in the Mazeppa and Gladys gas plants and related facilities to Dynegy Canada Inc. for $61.6 million. Additionally, under the sale agreement, Compton is assured processing and transportation capacity at set rates and will receive incentive payments for each of 50 wells to be drilled in the area. Under the incentive payment arrangement, Compton receives a minimum of $250,000 per well, increasing to a maximum of $500,000 per well, dependent on productivity, for each of the 50 wells.
- On December 21, 1998, Compton acquired J.M. Huber Canada Limited for $100.9 million. The acquisition effectively doubled the Company's production adding approximately 5,500 boe/d production and established reserves of 13.5 million boe.

The above transactions have positioned Compton for continued growth in the future:

- The proceeds from the sale of Compton's processing facilities eliminated the Company's then existing bank debt. The drilling incentive arrangement with Dynegy provides Compton with additional capital to fund its Southern Alberta exploration program and maintain low Finding and Development costs.
- The Huber acquisition added two new core producing areas and balanced the Company's risk profile through the addition of quality exploitation and development plays.

Revenue

Revenue, before royalties, for 1998 was $30.5 million, an increase of 73% from $17.7 million in the previous year. The increase in revenue did not keep pace with the increase in production in 1998, which rose 96% over 1997, due to lower commodity prices realized in 1998 (see Netbacks).

An analysis of revenue is provided below.

Revenue ($000s)

Year ended December 31	1998	1997
Gas revenue	$ 24,133	$ 12,091
Liquids	3,870	3,138
Oil	1,355	1,847
Processing and other	1,187	597
Total	$ 30,545	$ 17,673

Royalties

Royalties, before tax credits, as a percentage of production revenue, remained virtually unchanged at 16.8% in 1998 compared to 16.9% in 1997. Tax credits include Alberta Royalty Tax Credits (ARTC), Gas Cost Allowance (GCA) and Custom Processing Credits. ARTC's increased significantly with the increase in qualifying Crown Royalties and GCA credits include an adjustment to 1997. As a result, royalties, net of credits, decreased to 9.5% of production revenue in 1998 from 14.6% in 1997.

In 1999, the Company's ARTC claim will be limited to the maximum available to corporations and Compton expects its net royalty rate to be in the range of 14% to 15% of production revenue.

Royalties ($000s)

Year ended December 31	1998	% of Revenue	1997	% of Revenue
Crown royalties	$ 3,711	12.6	$ 2,281	13.4
Other royalties	1,221	4.2	604	3.5
	4,932	16.8	2,885	16.9
Royalty credits	(2,142)		(392)	
Royalties, net	$ 2,790	9.5	$ 2,493	14.6

Operating Costs

Operating costs for 1998, on a boe of production basis, remained relatively consistent with 1997 and averaged $4.94 per boe as compared to $4.91 per boe in 1997. Effective July 1, 1998, the Company sold its gas processing facilities and now pays fixed custom processing fees. Pursuant to the sale agreement, a favorable fee structure was arranged which, in conjunction with low oil operating costs and economies of scale from increased production, should result in overall 1999 operating costs remaining below $5.00 per boe.

Netbacks

Year ended December 31	1998			1997		
	Gas mcf	Oil & Liquids bbls	Total boe	Gas mcf	Oil & Liquids bbls	Total boe
Revenue	$ 2.00	$ 17.16	$ 19.40	$ 2.04	$ 26.78	$ 21.89
Royalties, net	(0.15)	(3.05)	(1.85)	(0.28)	(4.32)	(3.18)
Operating costs	(0.55)	(2.86)	(4.94)	(0.50)	(4.48)	(4.91)
Netback	$ 1.30	$ 11.25	$ 12.61	$ 1.26	$ 17.98	$ 13.80

General and Administrative Expenses

General and administrative expenses reflect the overall growth of the Company in 1998 and increased to $1.5 million from $0.9 million in 1997. On a boe basis, however, 1998 costs decreased from $1.17 per boe in 1997 to $1.00 per boe in 1998. Compton does not capitalize any overhead costs; however, salary costs directly related to exploration and development activities are capitalized. Such costs increased 106% from $248,784 in 1997 to $512,094 in 1998. During the later half of 1998, Compton increased its exploration team from six individuals at December 31, 1997 to 17 at December 31, 1998.

Norm Knecht, C.A.
V.P. Finance and C.F.O.

Compton now has the exploration personnel necessary to explore its extensive undeveloped land base and meet its 1999 target of 65 drill wells. With increased production, general and administrative costs in 1999 are budgeted at less than $0.75 per boe of production.

Interest Expense

During the first half of 1998, Compton's average outstanding debt was $46.8 million. With the closing of the sale of the Company's processing facilities in August, Compton became debt free until its acquisition of J.M. Huber Canada Limited in December 1998. At that time, the Company drew upon its bank credit facilities to fund the purchase. Total interest costs for 1998 were $2,020,914 of which $997,432, relating to debt associated with the purchase of the Mazeppa gas plant in 1997, was added to the cost of the facilities.

Depletion, Depreciation and Amortization

The provision for depletion, depreciation of property and equipment which includes a provision for the future costs of abandonment and site restorations, increased 71% from $3,896,132 in 1997 to $6,670,709 in 1998 reflecting 1998 increased production. On a boe of production basis, the provision declined from $5.05 per boe in 1997 to $4.41 per boe in 1998. This decline resulted primarily from the carrying costs of Property and Equipment being reduced by the proceeds from the sale of gas processing facilities at Gladys and Mazeppa during 1998.

Ceiling Test

In accordance with the Canadian Institute of Chartered Accountants full cost accounting guidelines, the Company performs an annual ceiling test calculation, whereby the net book value of the Company's oil and gas properties is compared to the estimated future value of its proven reserves. Reserves are valued based upon year end constant prices. At December 31, 1998, the estimated future value of proven reserves, so calculated, exceeded the book value of oil and gas properties by approximately $86 million.

Income Taxes

Deferred income taxes of $4,261,810, at an effective rate of $38.5%, were provided for on earnings of $11,068,348 in 1998 compared to $2,415,221, at a rate of 37.9%, in 1997. Additionally, the Company recognized a deferred tax liability of $5,437,910 relating to the gain, for tax purposes, realized on the sale of its gas plants and processing facilities.

The Company has estimated income deductions of $91.8 million available at December 31, 1998 and does not expect to pay any current taxes, other than Large Corporations Tax, in 1999.

Capital Expenditures

Net capital expenditures, as summarized on the following page, totaled $69.9 million and resulted in an increase in reserves of 14.9 million boe before production, on a proved plus 1/2 probable basis. 1997 expenditures of $92.9 million resulted in an increase in reserves of 13.2 million boe.

Capital Expenditures ($000s)	1998	1997
Property and lease expenditures	$ 8,092	$ 35,719
Exploration, development and exploitation	23,831	17,989
Production equipment and facilities	7,686	38,952
Other	511	237
	$ 40,120	$ 92,897
Acquisitions, corporate	91,394	–
Dispositions	(61,613)	–
Total, net	$ 69,901	$ 92,897

Finding and Development Costs

Since commencing operations in 1993, Compton's average finding and development (F&D) costs are $5.14 per established boe.

Finding and development costs in 1998, including the Huber acquisition, were $4.70 per established boe as compared to $7.06 per established boe in 1997. 1997 F&D costs included $2.82 per established boe relating to the acquisition and expansion of gas processing facilities and related infrastructure in Southern Alberta. The disposition of the facilities in 1998 resulted in a recovery of those costs and a reduction of 1998 F&D costs.

Brenda Austin, CMA
Controller

Compton's F&D costs compare very well with industry norms, and with the drilling incentives received pursuant to the sale of its processing facilities, the Company expects 1999 costs to approximate its average.

Liquidity and Capital Resources

Compton is a full cycle exploration and development company with a primary focus on natural gas. Capital expenditures on exploration, development and on stream activities precede the resultant production and cash flow, often by a significant time period. Continued growth and the ability to capitalize on opportunities as they arise may require capital expenditures in excess of funds generated through operating activities. To meet its needs in 1998, Compton monetized its gas processing facilities, as previously discussed, for $61.6 million and completed an equity financing for net proceeds of $12.9 million. In addition, the Company has a $105 million credit facility with a Canadian chartered bank of which $93.6 million had been drawn upon as at December 31, 1998, to fund the Huber acquisition.

Compton is committed to maintaining a strong financial position to mitigate the inherent risk of commodity pricing volatility and provide the Company the flexibility to pursue opportunities as they arise. Compton's current debt is approximately two times forward cash flow. It is the Company's intent to maintain and improve upon this ratio.

The Company's 1999 capital expenditure program is budgeted at $64 million. Compton has the ability to internally fund this program through cash flow, drilling incentives and the sale of certain non-core minor properties acquired in the Huber acquisition.

Net Asset Value

Compton has determined a net asset value as at December 31, 1998 based upon established reserves discounted at 10% and 15% as calculated below.

Net Asset Value ($ million)	10% DCF	15% DCF
Petroleum and natural gas properties	$ 275.5	$ 222.3
Undeveloped land	28.8	28.8
Working capital	0.3	0.3
Seismic and other	12.9	12.9
Drilling incentives	14.3	14.3
	$ 331.8	$ 278.6
Bank debt	(93.6)	(93.6)
Site restorations	(1.3)	(1.3)
Net asset value	$ 236.9	$ 183.7
Net asset value per share	**$ 2.46**	**$ 1.91**
Common shares issued and outstanding (millions)	96.3	96.3

Net asset value is based upon commodity price assumptions as at December 31, 1998 and reflect an oil price of $14.25 U.S. and a gas price of $2.20 Cdn. for 1999 and escalating therefter.

Business Conditions and Risk

Compton's operations are subject to risks normally associated with the oil and gas industry. These risks include:

- Inherent industry risk that exploration and development programs undertaken will result in economic reserve additions to replace production.

  Compton's strategies to minimize this inherent risk include a focus on select areas in Western Canada utilizing a team of highly qualified professionals with expertise and experience in assigned areas, expanding operations in core areas, continuously assessing strategic acquisitions to compliment existing activities and striving for a balance between exploration and lower risk development and exploitation prospects.

- Commodity and expenditure price shifts due to changes in supply, demand and markets.

  Commodity prices are driven by supply, demand and market forces outside the Company's influence. Compton monitors and focuses its expenditures to reflect price and production changes. Compton continuously monitors market conditions and opportunities. Currently the majority of the Company's gas production is marketed under contracts to aggregators. The Company has not entered into any price hedges in anticipation of predicted price increases however, as prices strengthen and production not subject to existing contracts comes on-stream, such arrangements will be considered. Compton's expenditures are subject to price changes and inflation. The Company considers longer-term contracts with suppliers, where appropriate, to mitigate such changes. Additionally, Compton has no control over government intervention or taxation levels on the industry.

- Mechanical and operational risks associated with the drilling for, production and processing of natural gas and crude oil including damage to the Company's equipment and the liability associated with an occurrence or malfunction.

  Compton manages operational risks through employing skilled professionals utilizing leading edge technology and conducting regular maintenance and training programs. The Company has an operational emergency response plan and has an operational safety manual. In addition, a comprehensive insurance program is maintained to mitigate risks and protect against significant losses.

- Environmental risk and impact resulting from the Company's field operations.

  Compton operates in accordance with all environmental legislation. The Company strives to maintain and surpass compliance with such regulations and works with government agencies, land-holders and other parties to minimize the environmental impact of its activities.

Year 2000

The Year 2000 (Y2K) issue arises because many computerized systems use two digits rather than four to identify a year. Date sensitive systems may recognize the year 2000 as some other date or fail completely. Additionally, similar problems could result in systems that use 1999 to represent something other than a date. Management has implemented a formal program to assess the Company's critical computerized systems and prepare for potential problems resulting from Y2K issues. The program has been developed by a project team, comprised of members of senior management, representatives from all areas of business, and includes the services of an external consulting group to direct and advise the project team. This program and its status are summarized below.

- Inventory and assess all computerized systems, information technology assets and embedded systems.

  All systems and assets have been inventoried and assessed. Critical systems have been identified and prioritized.

- Correct or replace those systems determined to be deficient.

  System remedies have begun, all critical systems have been remedied and other system remedies are scheduled for completion by July 1999.

- Test and validate remedied systems.

  Testing of remedied systems is underway and will continue through to the end of September 1999.

- Assess key business partners, suppliers and vendors as to their Y2K preparedness.

  Key suppliers are currently being contacted and monitored to ensure they are addressing Y2K issues.

- Develop contingency plans to address any potential problems identified and unforeseen problems that may arise.

  Contingency planning has commenced and will be ongoing throughout 1999.

Management believes the efforts as summarized above, will enable the Company to continue its business in an uninterrupted fashion, and that any Y2K related difficulties will not materially affect the financial position of the Company.

Consolidated Financial Statements

December 31, 1998

Management's Responsibility for Financial Statements

The accompanying consolidated financial statements of Compton Petroleum Corporation and all other financial and operating information contained in this Annual Report are the responsibility of management. The consolidated financial statements have been prepared in accordance with accounting policies detailed in the notes to the financial statements and in accordance with generally accepted accounting principles in Canada.

The Company's systems of internal control have been designed and maintained to provide reasonable assurance that assets are properly safeguarded and that the financial records are sufficiently well maintained to provide relevant, timely and reliable information to management.

External auditors, appointed by the shareholders, have independently examined the consolidated financial statements. They have performed such tests as they deemed necessary to enable them to express an opinion on these financial statements.

An Audit Committee of the Board of Directors has reviewed these consolidated financial statements with management and the external auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

E.G. Sapieha
President and
Chief Executive Officer

N.G. Knecht
Vice President, Finance and
Chief Financial Officer

Auditors' Report

To the Shareholders of Compton Petroleum Corporation

We have audited the consolidated balance sheets of Compton Petroleum Corporation as at December 31, 1998 and 1997 and the consolidated statements of earnings and retained earnings and changes in financial position for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1998 and 1997 and the results of its operations and the changes in its financial position for the years then ended in accordance with generally accepted accounting principles.

Grant Thornton

Chartered Accountants
Calgary, Alberta
April 13, 1999

Consolidated Balance Sheets

December 31		1998		1997
Assets				
Current				
Accounts receivable	$	25,433,255	$	8,788,043
Notes receivable (Note 5)		150,000		345,000
Property and equipment (Note 6)		186,499,612		113,043,056
	$	212,082,867	$	122,176,099
Liabilities				
Current				
Accounts payable and accruals	$	25,125,764	$	11,938,698
Long-term debt (Note 7)		93,615,801		41,768,891
Deferred income taxes		10,769,991		1,368,807
Site restoration and abandonments (Note 8)		1,304,351		73,538
		130,815,907		55,149,934
Shareholders' Equity				
Capital stock (Note 9)		70,532,265		62,617,533
Retained earnings		10,734,695		4,408,632
		81,266,960		67,026,165
	$	212,082,867	$	122,176,099

Year 2000 (Note 12)

See accompanying notes to the consolidated financial statements.

On behalf of the Board

Director

Director

Consolidated Statements of Earnings and Retained Earnings

Year ended December 31	1998	1997
Revenue		
Oil and gas revenues	$ 30,545,450	$ 17,673,456
Royalties, net	(2,789,635)	(2,452,949)
	27,755,815	15,220,507
Expenses		
Operating	7,476,497	3,786,863
General and administrative	1,516,779	902,879
Interest	1,023,482	270,036
Depletion, depreciation and amortization	6,670,709	3,896,132
	16,687,467	8,855,910
Earnings before taxes	11,068,348	6,364,597
Taxes		
Income taxes, deferred (Note 10)	4,261,810	2,415,221
Capital taxes	202,344	224,073
	4,464,154	2,639,294
Net earnings	6,604,194	3,725,303
Retained earnings, beginning of year	4,408,632	683,329
Premium on redemption of shares (Note 9)	(278,131)	–
Retained earnings, end of year	$ 10,734,695	$ 4,408,632
Earnings per share (Note 11)		
Basic	$ 0.07	$ 0.06
Fully diluted	$ 0.06	$ 0.05

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Financial Position

Year ended December 31	1998	1997
Cash derived from (applied to)		
Operating		
Net earnings	$ 6,604,194	$ 3,725,303
Depletion, depreciation and amortization	6,670,709	3,896,132
Deferred income taxes	4,261,810	2,415,221
Cash flow from operations	17,536,713	10,036,656
Change in non-cash operating working capital	(3,458,145)	468,687
	14,078,568	10,505,343
Financing		
Repayment of notes receivable	195,000	–
Proceeds from share issues, net	13,824,142	38,777,166
Proceeds from long-term debt	51,846,910	41,768,891
Redemption of common shares	(562,494)	–
	65,303,558	80,546,057
Investing		
Property and equipment additions	(40,120,044)	(92,897,408)
Acquisitions (Note 3)	(91,394,506)	–
Proceeds on sale (Note 4)	61,613,424	–
	(69,901,126)	(92,897,408)
Working capital acquired (Note 3)	(9,481,000)	–
	(79,382,126)	(92,897,408)
Decrease in cash	–	(1,846,008)
Cash, beginning of year	–	1,846,008
Cash, end of year	$ –	$ –
Cash flow from operations per share (Note 11)		
Basic	$ 0.20	$ 0.16
Fully diluted	$ 0.17	$ 0.14

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

December 31, 1998 and 1997

1. Nature of operations

The Company is engaged primarily in the exploration for and production of petroleum and natural gas reserves in a single cost centre being Western Canada.

2. Significant accounting policies

a) Principles of consolidation

The consolidated financial statements include the accounts of Compton Petroleum Corporation and its wholly-owned subsidiary, Compton Energy Inc. (formerly J.M. Huber Canada Limited).

b) Petroleum and natural gas properties

i) Capitalized costs

The Company follows the full cost method of accounting for its petroleum and natural gas operations. Under this method all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Costs include lease acquisition costs, geological and geophysical expenses, interest on debt directly related to certain acquisitions, and costs of drilling both productive and non-productive wells. Proceeds from the sale of properties will be applied against capitalized costs, without any gain or loss being realized, unless such sale would significantly alter the rate of depletion and depreciation.

ii) Depletion and depreciation

Depletion of exploration and development costs and depreciation of production equipment is provided using the unit-of-production method based upon estimated proved petroleum and natural gas reserves. The costs of significant undeveloped properties are excluded from costs subject to depletion. For depletion and depreciation purposes, relative volumes of petroleum and natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Depreciation of office equipment is provided for on a declining-balance basis at 20% per annum.

iii) Ceiling test

In applying the full cost method, the Company calculates a ceiling test whereby the carrying value of petroleum and natural gas properties and production equipment, net of recorded deferred income taxes and the accumulated provision for site restoration and abandonment costs, is compared annually to an estimate of future net cash flow from the production of proved reserves. Net cash flow is estimated using year end prices, less estimated future general and administrative expenses, financing costs and income taxes. Should this comparison indicate an excess carrying value, the excess is charged against earnings as additional depletion and depreciation.

iv) Future site restoration and abandonment costs

Estimated costs of future site restoration and abandonments, net of recoveries, are provided for over the life of proved reserves on a unit-of-production basis. An annual provision is recorded as additional depletion and depreciation. The accumulated provision is reflected as a non-current liability and actual expenditures are charged against the accumulated provision when incurred.

c) Use of estimates

The preparation of financial statements in accordance with generally accepted accounting principles requires management to make assumptions and estimates that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from and affect the results reported in these financial statements.

d) Financial instruments

Financial instruments of the Company include accounts receivable, notes receivable, accounts payable and accruals and long-term debt. Unless otherwise disclosed, there are no significant differences between the carrying value of these amounts and their estimated fair value.

e) Joint operations

Certain petroleum and natural gas activities are conducted jointly with others. These consolidated financial statements reflect only the Company's proportionate interest in such activities.

f) Flow-through shares

Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. Petroleum and natural gas properties and capital stock are reduced by the estimated tax benefits transferred to shareholders.

3. Acquisitions

On December 21, 1998 the Company acquired all of the issued and outstanding shares of J. M. Huber Canada Limited ('Huber'), for cash consideration of $100,875,506. Huber, a subsidiary of a US corporation, was engaged in oil and gas exploration activities primarily in Alberta. The transaction has been accounted for by the purchase method and the consolidated financial statements include the results of the operations from date of acquisition. The fair value of the assets acquired is as follows:

Oil and gas reserves and facilities	$ 87,021,506
Undeveloped lands	4,373,000
	91,394,506
Working capital	9,481,000
Net assets acquired	$ 100,875,506

4. Disposition

During 1998, the Company sold all of its interests in certain gas processing facilities and related infrastructure, for cash proceeds of $61,613,424. The proceeds from the sale, net of deferred taxes of $ 5,437,910, have been charged against capitalized property and equipment costs without any gain being recognized.

Additionally, under an incentive payment arrangement, relating to 50 wells to be drilled in the Okotoks/Nanton area, the purchaser will pay the Company a minimum of $250,000 per well to a maximum of $500,000 per well depending upon well productivity. The Company will recognize the payments as a reduction of exploration costs when amounts become due.

5. Notes receivable

The Company granted loans to officers of the Company to facilitate the exercise of options, granted prior to the Company filing an Initial Public Offering, to acquire common shares of the Company.

The loans are demand in nature and repayable at the earlier of such demand or their Maturity Date being the date the officer ceases to be employed by the Company. The loans are non-interest bearing until the Maturity Date, at which time interest is calculated monthly at the bank prime rate plus 5%. The Company holds in trust the shares, issued on exercise of the options, as security for the loans. As at December 31, 1998 the amount outstanding for these loans was $150,000, (1997 – $345,000).

6. Property and equipment

	1998	1997
Exploration and development costs	$ 191,044,431	$ 73,693,592
Accumulated depletion	(8,791,762)	(3,246,282)
	182,252,669	70,447,310
Production equipment and processing facilities	4,346,648	43,921,679
Office and equipment	798,730	287,878
	5,145,378	44,209,557
Accumulated depreciation	(898,435)	(1,613,811)
	4,246,943	42,595,746
	$ 186,499,612	$ 113,043,056

The Company does not capitalize any portion of its general and administrative expenses. Interest expense of $997,432 (1997 – $896,324) associated with certain processing facilities has been capitalized.

Future capital expenditures of $12,652,000 (1997 - $3,836,000), as estimated by independent engineers, relating to the

development of proved non-producing reserves have been included in costs subject to depletion, and undeveloped properties with a cost of $28,768,300 (1997 - $13,295,722), included in exploration and development costs, have not been subject to depletion.

7. Long-term debt

	1998	1997
Revolving bank credit facility	$ 93,615,801	$ 41,768,891

At December 31, 1998 the Company had a revolving credit facility in the amount of $105,000,000 (1997 – $52,000,000) with a Canadian chartered bank. The loan facility provides that advances may be made by way of direct advances, bankers' acceptances or U.S. dollar Libor advances. Borrowings under this facility bear interest at various rates approximating the bank's prime lending rate, depending upon the nature of the advances. The facility is subject to quarterly reductions, of $1,500,000 commencing July 1, 1999.

Additionally, the Company has available a bridge facility with an authorized limit of $15,000,000 which has not been drawn upon.

The security pledged for both the operating and the bridge facility consists of a demand fixed and floating charge debenture in the principal amount of $200,000,000, on all the assets of the Company.

8. Site restoration and abandonments

At December 31, 1998 total future removal and site restoration costs to be accrued over the life of the remaining proven reserves were estimated at $4,562,718 (1997 - $1,543,340) of which $1,304,351 (1997– $73,538) has been provided for. This estimate is subject to change based on amendments to environmental laws as new information concerning operations becomes available.

9. Capital stock

a) Authorized:

Unlimited number of common shares

Unlimited number of preferred shares, issuable in series

b) Issued and outstanding:

	1998		1997	
	Number of Shares	Amount	Number of Shares	Amount
Common shares				
Beginning of year	80,099,213	$ 47,473,593	57,383,000	$ 22,790,666
Issued during the year	16,598,802	23,243,447	22,716,213	24,682,927
Warrants	–	100,000	–	–
Redemption of shares	(389,300)	(284,775)	–	–
End of year	96,308,715	70,532,265	80,099,213	47,473,593
Special warrants				
Beginning of year	8,308,500	15,143,940	926,213	471,842
Issued during the year	–	–	8,308,500	15,143,940
Exercised during year	(8,308,500)	(15,143,940)	(926,213)	(471,842)
End of year	–	–	8,308,500	15,143,940
Total	96,308,715	$ 70,532,265	88,407,713	$ 62,617,533

1998

During the year ended December 31, 1998 the Company issued 16,598,802 common shares as follows:

i) On various dates; 1,123,332 common shares at an average price of $0.77 per share for proceeds of $870,330 on the exercise of previously granted stock options.

ii) On various dates; 176,667 common shares at prices ranging from $1.40 to $1.60 per share , for proceeds of $260,000 on

the acquisition of certain properties and for services provided to the Company by independent third parties.

iii) On January 31; 7,700,000 common shares on the exercise of 7,700,000 special warrants issued on November 4, 1997 at a price of $1.95 per share for net proceeds of $14,554,269 after deduction of issue expenses of $460,731 (net of associated tax benefit of $370,914).

iv) On December 30; 6,990,303 common shares issued on a flow-through basis, at a price of $1.90 per share for net proceeds $12,892,760, after deducting issue expenses of $388,816 (net of associated tax benefit of $298,546). The common shares have been recorded at $6,969,177 being net proceeds less estimated tax benefits of $5,923,583 renounced to shareholders.

v) On December 31; 608,500 common shares on the exercise of 608,500 special warrants issued, on a flow-through basis, on December 31, 1997 for net proceeds of $1,058,216 after deducting issue expenses of $6,659 (net of associated tax benefits of $5,461). The common shares have been recorded at $589,671 being net proceeds less estimated tax benefits of $468,545 transferred to shareholders.

During 1998, pursuant to a normal course issuer bid, the Company purchased and cancelled 389,300 common shares having an average value of $284,775. The total cost of the purchase was $562,494 which exceeded the average carrying value by $278,131 which was charged against retained earnings.

1997

During the year ended December 31, 1997 the Company issued 22,716,213 common shares and 8,308,500 special warrants as follows:

i) June 25, 1997; 50,000 common shares at a price of $0.85 per share for proceeds of $42,500 on the exercise of previously granted stock options.

ii) October 9, 1997; 21,740,000 common shares at a price of $1.15 per share pursuant to the exercise of special warrants issued on July 3, 1997, for net proceeds of $24,168,585 after deducting issue expenses of $832,415 (net of associated tax benefits of $670,139).

iii) November 4, 1997; 7,700,000 special warrants at a price of $1.95 per special warrant for net proceeds of $14,554,269 after deducting issue expenses of $460,731 (net of associated tax benefits of $370,914). Each special warrant entitles the holder to acquire one common share without additional consideration. The special warrants were exercised on January 30, 1998.

iv) December 30, 1997; 926,213 common shares on the exercise of special warrants, issued on a flow-through basis, on December 30, 1996. The special warrants were recorded at $471,842 being net proceeds less the estimated tax benefits of $392,433 renounced to shareholders.

v) December 31, 1997; 608,500 special warrants at a price of $1.75 per special warrant for net proceeds of $1,058,216 after deducting issue expenses of $6,659 (net of associated tax benefit of $5,461). Each special warrant entitles the holder to acquire one common share, on a flow-through basis, without additional consideration. The special warrants have been recorded at $589,671 being net proceeds less the estimated tax benefit of $468,545 transferred to shareholders. The special warrants were exercised on December 31, 1998.

c) Outstanding options

The Company has implemented a Stock Option Plan, for directors, officers and senior employees. Under the plan 9,000,000 common shares are reserved for issuance to eligible participants. At December 31, 1998 options to acquire 7,478,334 (1997 - 7,025,000) shares were outstanding under the plan at a weighted average price of $0.96 per share (1997 - $0.81). The options expire at various dates between September 2006 and September 2008. At December 31, 1998, 4,784,999 (1997 - 4,825,000) options had vested with the holders thereof.

d) Outstanding warrants

In conjunction with the Disposition, outlined in note 4, the Company issued share purchase warrants to the third party purchaser, which entitle the purchaser to acquire a maximum of 3,000,000 common shares of the Company as outlined below:

i) 2,000,000 common shares at a price of $1.60 per share on or before August 28, 2001.

ii) 1,000,000 common shares at a price of $1.75 per share on or before August 28, 2003. The warrants may be exercised on the basis of 10,000 warrants for each $250,000 paid to the Company as an incentive fee under the terms of the disposition.

e) Shareholder rights plan

On January 28, 1997, the directors of the Company approved a Shareholder Rights Plan to ensure all shareholders are treated fairly in the event of a takeover offer or other acquisition of control of the Company.

Pursuant to the Plan, the Board of Directors authorized and declared the distribution of one Right in respect of each common share outstanding as at January 28, 1997. In the event an acquisition of 20% or more of the Company's shares is completed and the acquisition is not a permitted bid, as defined by the Plan, each Right will permit the holder to acquire, at the exercise price of $8.00, such number of common shares as have a market value equal to twice the exercise price.

10. Income taxes

a) Provision for income taxes

		1998		1997
Earnings before taxes	$	11,068,348	$	6,364,597
Expected tax expense at combined federal and provincial rates of approximately 44.6%	$	4,936,483	$	2,838,609
Increase (decrease) resulting from:				
Non-deductible crown charges		1,495,400		1,017,581
Depletion of assets without a tax base		180,983		63,442
Royalty tax credits included in income		(639,055)		(192,758)
Resource allowance		(2,183,423)		(1,311,653)
Other		471,422		–
Provision for income taxes, deferred	$	4,261,810	$	2,415,221

b) Available tax deductions

The Company has available the following approximate amounts which may be deducted, at the annual rates indicated, in determining taxable income of future years:

	Rate		1998		1997
Undepreciated capital cost	25%	$	8,365,000	$	42,779,000
Canadian oil and gas property expense	10%	$	51,450,000	$	42,229,000
Canadian development expense	30%	$	25,576,000	$	7,299,000
Canadian exploration expense	100%	$	3,394,000	$	11,195,000
Share issue costs	20%	$	3,006,000	$	2,498,000

11. Weighted average number of common shares

	1998	1997
Weighted average number of common shares outstanding during the year	88,731,497	62,357,582
Fully diluted weighted average number of common shares outstanding during the year	104,141,409	75,144,894

Fully diluted earnings and cash flow per share reflect the effect of the special warrants from their issue date and stock options outstanding at year end.

12. Year 2000

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 Issue may be experienced before, on, or after January 1, 2000 and, if not addressed, the impact on operations and financial reporting may range from minor errors to significant systems failure which could affect an entity's ability to conduct normal business operations. It is not possible to be certain that all aspects of the Year 2000 Issue affecting the entity, including those related to the efforts of customers, suppliers, or third parties, will be fully resolved.

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